EPA

UNDERGROUND INJECTION CONTROL PROGRAM

AREA PERMIT

PREPARED: November 2009

Permit No. CO12143-00000

Class I Non-Hazardous Waste Disposal Well

ECCV RO Disposal Well

Issued To

East Cherry Creek Valley Water Sanitation District
6201 S. Gun Club Road
Aurora, CO 80016

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Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

East Cherry Creek Valley Water & Sanitation District
6201 S. Gun Club Road
Aurora, CO 80016

hereby referred to as the "Permittee", is authorized to construct and operate the following Non-Hazardous Class I injection well or wells:

well #

ECCV DI-1
517 FSL, 649 FWL, SWSW S1, T1S, R66W
Adams County, CO
-08425

ECCV DI-2
610 FNL, 51 FEL, NENE S1, T1S, R66W
Adams County, CO
-08426

ECCV DI-3
3365 FSL, 702 FWL, SWNW S12, T1S, R66W
Adams County, CO
-08427

located wholly within the area permit boundary described by (commencing from the northeast corner and continuing clockwise):

190 feet FNL, 650 feet FWL, S6, T1S, R65W
1080 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 0 feet FWL, S12, T1S, R66W
2900 feet FNL, 775 feet FEL, S11, T1S, R66W
2690 feet FNL, 960 feet FEL, S11, T1S, R66W
1890 feet FNL, 0 feet FEL, S11, T1S, R66W
640 feet FSL, 0 feet FWL, S1, T1S, R66W
190 feet FNL, 0 feet FEL, S1, T1S, R66W

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations (40 CFR §144.35).

This Permit is issued for 10 years from the Effective Date unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: APR 30 2010 Effective Date APR 30 2010

SASHaw for

Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) recording devices capable of continuously monitoring, within a certified accuracy of 95% or better, the following:

(i) injection pressure, flowrate, volume, and

(ii) wellhead pressure readings from the tubing-casing; and

(b) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(c) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

(i) on the injection tubing; and

(ii) on the tubing-casing annulus (TCA); and

(d) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(e) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

6. Annual Pressure Falloff Test

The operator must perform a pressure falloff test at least once every twelve months. The pressure falloff test is required for Class I operations [40 CFR 146.13 (d)(1)] to monitor pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone and to aid in determining the lateral extent of the injection plume.

The operator is required to prepare a plan for running the yearly falloff test. EPA Region VI has developed a set of guidelines that should be used by the operator when developing their site specific plan. The Region VI "UIC Pressure Falloff Testing Guideline" is available from EPA and will be provided upon request. The final test plan shall be submitted to Region VIII for review at least 30 days prior to conducting the annual pressure falloff test.

It is important that the initial and subsequent tests follow the same test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. The permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information on any reservoir boundaries, an estimate of the well skin effect and reservoir flow conditions. The report shall also compare the test results with the previous years test data, unless it is the first test performed for that well, and shall be prepared by a knowledgeable analyst.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

(a) There is no significant leak in the casing, tubing, or packer (Part I); and

(b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in APPENDIX B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least 30 days prior to any scheduled mechanical integrity test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. *Loss of Mechanical Integrity.*

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. *Requirements Prior to Commencing Injection.*

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-9 or 7520-12; all applicable logging and testing requirements of this permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. *Injection Interval.*

Injection is permitted only within the approved injection interval listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. *Injection Pressure Limitation*

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Except during stimulation and performing required formation test(s), injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. *Injection Volume Limitation.*
Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation.*

Approved injected fluids are limited to non-hazardous waste fluid generated by the East Cherry Creek Valley Water and Sanitation District from their reverse osmosis plant and products injected for well workover and maintenance of the well(s). The waste stream is the concentrate or retentate from treating water from their drinking water supply wells through a reverse osmosis process to meet National Primary and Secondary Drinking Water Standards.

6. *Tubing-Casing Annulus (TCA)*
The tubing-casing annulus (TCA) shall be filled with fresh water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

7. *Well Injection and Seismicity*
If there is a reported seismic event, the Permittee shall immediately verify the event with the U.S. Geological Survey (USGS) Earthquake Hazards Program, either through their real time earthquake monitoring program that is readily available at http://earthquake.usgs.gov/earthquakes or personal communication. If a seismic event is verified within 2 miles of the permit area boundary, the Permittee will immediately cease injection. Injection shall not resume until the Permittee has obtained approval to recommence injection from EPA.

For any reported seismic event, whether or not it is has been verified through the USGS Earthquake Hazards Program, the Permittee shall notify EPA within twenty-four (24) hours according to Part III, Section E.11.

A reported seismic event shall be defined as either a citizen complaint or a seismic event recorded by the USGS Earthquake Hazard Program that is within 50 miles of the permit area boundary.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency.

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. Monitoring Methods.

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Continuous monitoring of the injection pressure, annulus pressure, injection rate, and injected volumes shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection and annulus pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected.

(e) Pressures are to be measured in pounds per square inch (psi).

(f) Fluid volumes are to be measured in standard oil field barrels (bbl).

(g) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Quarterly Reports.

Whether the well is operating or not, the Permittee shall submit Quarterly Reports to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D. The report of fluids injected during the quarter must identify each new fluid source by well name and location, and the field name or facility name.

The operator shall also provide summary graphs covering the reporting period of the injection pressure, annulus pressure, and injection rate. Copies of the analytical results for the samples of injected fluids, and records of any major changes in characteristics or sources of injected fluid shall be included in the Quarterly Report.

The Quarterly Report shall cover the period from the January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Quarterly Reports shall be submitted by the 15th day of the month following the end of the data collection period. EPA Form 7520-8 may be copied and used to submit the Quarterly Report providing the pressures, fluid volumes and rates in the units described in Part II Section D.2.(d) through Part II Section D.2.(f)

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. *Well Plugging Requirements*

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. *Approved Plugging and Abandonment Plan.*

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. *Forty Five (45) Day Notice of Plugging and Abandonment.*

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. *Plugging and Abandonment Report.*

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. *Inactive Wells.*

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class I injection well to a non-Class I well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Duty to Reapply.

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.

This Permit may be modified, revoked and reissued or teminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The ECCV DI-1, ECCV DI-2, ECCV DI-3 will be newly constructed wells drilled below to a total depth (TD) of approximately 10,500 feet. See Diagram.

Surface Casing: A 9.625" casing will be set below the Laramie-Fox Hills at approximately 1400 feet in a 12.25" hole and cemented to surface with approximately 557 sx of Class G + 2% CaCl2 cement.

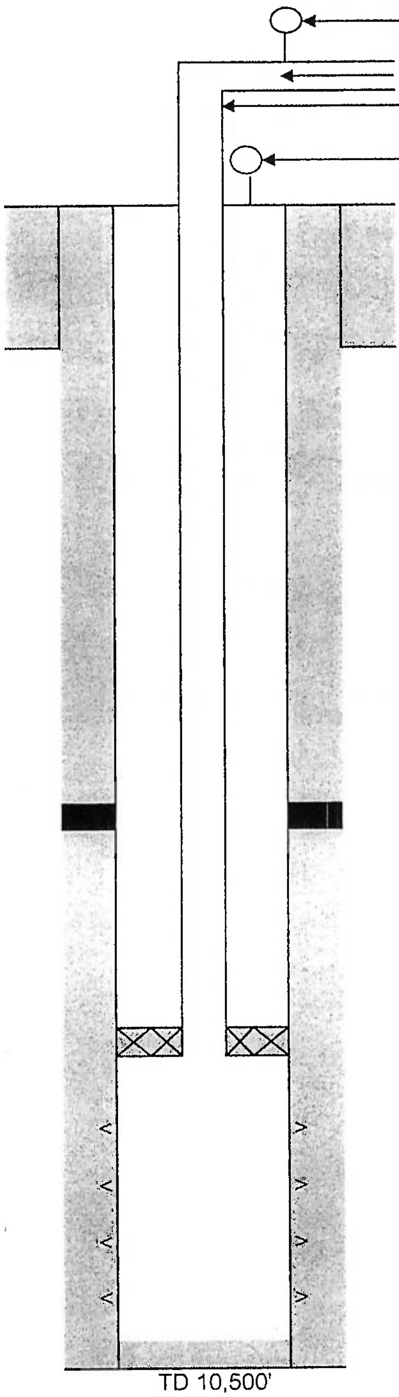
Production Casing: A 7" casing will be set at approximately 10,500 feet in an 8.75" hole and cemented to surface in two stages. A DV tool will be placed at approximately 7465 feet. The first stage will consist of approximately 164 sx of 13.4# PLC and 225 sx 15.8# Class G cement. The second stage above the DV tool will consist of approximately 367 sx of 11# PLC and 100 sx of 13.4# PLC.

Perforations: Perforations are shown on the generalized well schematic. The exact location of the perforations will be determined after the evaluation of the open hole logs.

Tubing and the packer will be installed no higher than 100 feet of the top open perforation.

Note: Depths are approximate and will be determined after the well has been drilled.

ECCV Beebe Deep Injection Well #1
Proposed Wellbore



Tubing Injection Pressure & Rate Continuously Monitore

Waste Water from RO Plant

Top connection 3 1/2" or 4-1/2" EUE

Surface Annulus Pressure Continuously Monitored

GL - 5030'
TOC at SURFACE (both casing strings)

BFW (Fox Hills Aquifer) @ 1200'
9-5/8" 36# @ 1400'
cmt w/ 557 (est) sks 15.3 lb/gal Class G + 2% CaCl2 (incl 50% excess)

DV tool @ 7465' (est)
2nd stage cement to surface: 1373 (est) cu ft slurry (incl 25% excess)
367 sx 11.0# PLC, 100 sx 13.4# PLC

Top of J (influences DV tool location) @ 7965' (est)

Injection packer at 9265' (est)

	Est Top	Perf?
Lyons	9307	Possible
L Satanka	9443	No
Wolfcamp	9685	Possible
Amazon	9771	Possible
Council Grove	9829	Possible
Admire	9981	Possible
Virgil	10033	Possible
Missourian	10283	Possible
Fountain	10381	No

7" 26# N-80 @ 10,500'
1st stage cement to DV: 510 (est) cuft slurry (incl 10% excess)
164 sx 13.4# PLC, 225 sx 15.8# Class G

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logs and tests shall be performed according to current EPA-approved procedures. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well logging or test required as a condition of this permit.

Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the log or test results.

Logs.

WELL NAME: ECCV DI-1, DI-2, and DI-3	
TYPE OF LOG	**DATE DUE**
Caliper	Surface and Longstring Casings: Prior to receiving authorization to inject.
Porosity	Longstring Casing: Prior to receiving authorization to inject.
SP	Surface and Longstring Casings: Prior to receiving authorization to inject.
Resistivity	Surface and Longstring Casings: Prior to receiving authorization to inject.
CBL/VDL/GAMMA RAY	Surface and Longstring Casings: Prior to receiving authorization to inject.

Tests.

WELL NAME: ECCV DI-1, DI-2, and DI-3	
TYPE OF TEST	**DATE DUE**
Source Sample	Prior to receiving authorization to inject, a sample of the injectate will be provided for all quarterly and annually SAMPLE AND ANALYZE analytes found in Appendix D.
Temperature Log	Run TEMP log to establish baseline prior to receiving authorization to inject, additionally within 6-12 months of injection, and at least once every five (5) years after the last successful demonstration of Part II MI.
Pressure Fall-Off Test	First test shall be run 6-12 months after authorization to inject, subsequent tests shall be conducted at least once every year thereafter.
Radioactive Tracer Survey (2)	If CBL does not show adequate cement behind casing across the confining zone, a RTS is req'd prior to authorization to inject.
Standard Annulus Pressure	Prior to authorization to inject and at least once every five (5) years after the last successful demonstration of Part I Mechanical Integrity.
Pore Pressure	Prior to receiving authorization to inject.
Step Rate Test	Prior to receiving authorization to inject. The SRT shall be performed following current EPA guidance. Four zones will be isolated and step rate tests will be conducted on each zone. These four zones are: 1) Missouri, 2) Virgil and Admire, 3) Council Grove, Amazon and Wolf Camp, and 4) Lyons. The L Satanka formation will not initially be used as an injection zone. In the zones where more than one formation is open to receive fluids during the step rate test, a spinner will be placed near the base of the uppermost formation.
Cement Records	Prior to receiving authorization to inject.
Injection Zone Water Sample	Prior to receiving authorization to inject, each formation will be isolated and a representative sample (stabilized specific conductivity from three successive swab runs) will be analyzed for TDS, pH, Specific Gravity and Specific Conductivity.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
ECCV DI-1	3,120
ECCV DI-2	3,120
ECCV DI-3	3,120

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

Note: Depths are approximate and will be determined after the well has been drilled.

FORMATION NAME	APPROVED INJECTION INTERVAL (GL, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Lyons	9,307.00 -	9,443.00	0.800
Lower Satanka (shale)	9,443.00 -	9,685.00	0.800
Wolfcamp	9,685.00 -	9,771.00	0.780
Amazon	9,771.00 -	9,829.00	0.780
Council Grove	9,829.00 -	9,981.00	0.780
Admire (no water sample)	9,981.00 -	10,033.00	0.750
Virgil	10,033.00 -	10,283.00	0.750
Missourian	10,283.00 -	10,381.00	0.750

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

RECORD	
CONTINUOUSLY	Injection pressure (psig)
	Injection rate (bbl/day)
	Annulus pressure(s) (psig)
	Fluid volume injected (bbls)
MONTHLY	Seismic events(s) within a 50 mile radius of the area permit boundary, gathered from the USGS Earthquake Hazard Program website or personal communication.

SAMPLE AND ANALYZE

The injectate is required to be sampled and analyzed on a quarterly or annually basis for the analytes listed below. However, if there is a change in operation that will affect the concentration, then the injectate fluid must be sampled and results submitted within 15 days of the change in operation.

If no injection occurs for the entire quarter or year, then Sample and Analyze requirements will not be required for that quarter or year.

Analytical method used must comply with analytical methods cited and described in Table 1 of 40CFR 136.3, Appendix II of 40 CFR 261, or those methods listed in the tables.

	Parameter Analyzed	**EPA Analytical Method**
QUARTERLY	Total Dissolved Solids (mg/l)	
	Total Suspended Solids (mg/l)	
	Specific Conductivity (umhos/cm)	
	pH	
	Specific Gravity	
	Corrosivity Index (Langelier Saturation Index)	
	Nitrate-Nitrite (both as N) (mg/L)	
	Sulfate (mg/L)	
	Chloride (mg/L)	
	Magnesium (mg/L)	
	Sodium (mg/L)	
	Calcium (mg/L)	
	Iron (mg/L)	
	Gross Alpha (pCi/L)	E900.0
	Gross Beta (pCi/L)	E900.0

SAMPLE AND ANALYZE		
ANNUALLY	Strontium (mg/L)	272.1, 272.2, 200.7
	Uranium-234 (pCi/L)	E907.0
	Uranium-238 (pCi/L)	E907.0
	Thorium-230 (pCi/L)	E907.0
	Radium-226 (pCi/L)	E903.0
	Radium-228 (pCi/L)	E904.0
	Potassium-40 (pCi/L)	E901.1
	Lead-210 (pCi/L)	E905.0 Mod.

REPORT	
QUARTERLY	Each month's minimum, average, and maximum injection pressures (psig)
	Each month's minimum, average, and maximum injection rate (bbl/day)
	Each month's minimum, average, and maximum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of quarterly and annually (if applicable) injected fluid analysis
	Sources of all fluids injected during the quarter
	Summary of monthly reviews of seismic event(s), within a fifty (50) mile radius of the area permit boundary, gathered from the USGS Earthquake Hazard Program website or personal communication

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

Prior to plugging the well, run a Mechanical Integrity Test, pull tubing, and repair any casing leaks. The construction plans call for a permanent packer to be installed, the packer can be pulled or left in place when the well is plugged and abandoned.

At a minimum, the following plugs are required:

PLUG NO. 1: Set a cement retainer at approximately 9215 feet (at most 50 feet above the uppermost perforation or the permanent packer, if the packer is not pulled). Squeeze sufficient quantity of cement through the retainer to plug the well from the base of the well to the cement retainer as well as squeeze through the perforations. Place approximately 100 feet of cement on top of cement retainer. This must extend a minimum 50 feet above the base of the confining layer, which the proposed plan presently more than exceeds (the estimated base of the Lykins is 9307 feet).

PLUG NO. 2: Set a balanced plug across the base of the Dakota formation approximately from 8200 feet to 8300 feet.

PLUG NO. 3: Set a balanced plug across the DV tool approximately from 7370 feet to 7500 feet.

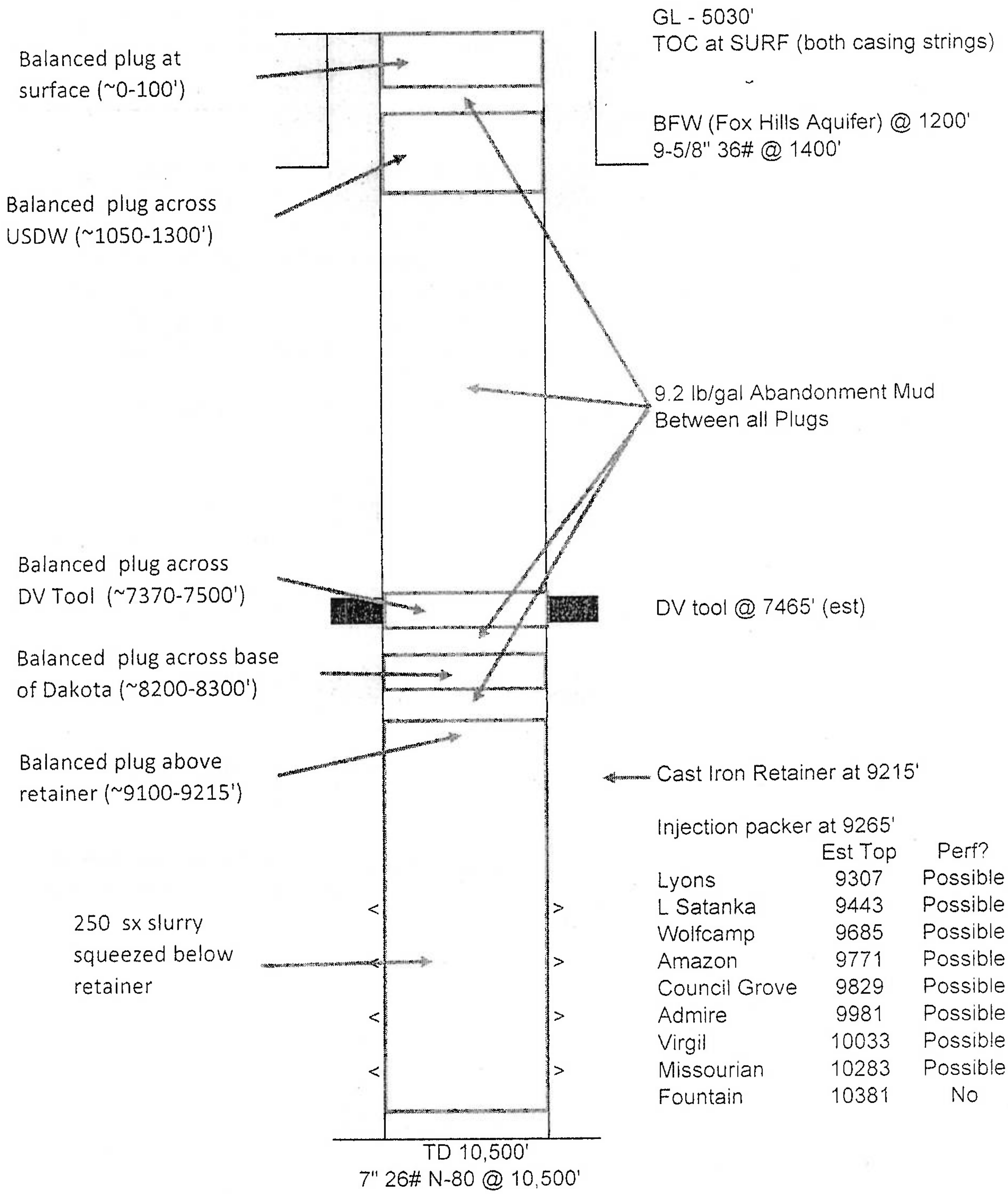
PLUG NO. 4: Set a balanced plug across the surface casing shoe from approximately 1050 feet to 1300 feet.

PLUG NO. 5: Set a surface plug from approximately 100' to surface.

NOTES:
Plug placement must be verified by tagging the top of the plug after the cement has had adequate time to set.

Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal should be used during plugging operations, and should remain between plugs in the well after cement plug placement.

ECCV Class I Non-Hazardous Disposal Well
Plugged and Abandonment Wellbore



STATEMENT OF BASIS

EAST CHERRY CREEK VALLEY WATER & SANITATION DISTRICT
ECCV RO DISPOSAL WELL

EPA AREA PERMIT NO. CO12143-00000

CONTACT: Wendy Cheung
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6242

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued 10 years from the effective date unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41.

PART I. General Information and Description of Facility

East Cherry Creek Valley Water & Sanitation District
6201 S. Gun Club Road
Aurora, CO 80016

on

June 1, 2009

submitted an application for an Underground Injection Control (UIC) Program Permit to construct and operate the following Class I injection well or wells:

well #

ECCV DI-1
517 FSL, 649 FWL, SWSW S1, T1S, R66W — 08425
Adams County, CO

ECCV DI-2
610 FNL, 51 FEL, NENE S1, T1S, R66W — 08426
Adams County, CO

ECCV DI-3
3365 FSL, 702 FWL, SWNW S12, T1S, R66W — 08426
Adams County, CO

located wholly within the area permit boundary described by (commencing from the northeast corner and continuing clockwise):

190 feet FNL, 650 feet FWL, S6, T1S, R65W
1080 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 0 feet FWL, S12, T1S, R66W
2900 feet FNL, 775 feet FEL, S11, T1S, R66W
2690 feet FNL, 960 feet FEL, S11, T1S, R66W
1890 feet FNL, 0 feet FEL, S11, T1S, R66W
640 feet FSL, 0 feet FWL, S1, T1S, R66W
190 feet FNL, 0 feet FEL, S1, T1S, R66W

The East Cherry Creek Valley Water and Sanitation District (ECCV) is applying for an area permit that includes three Class I non-hazardous disposal wells for the purpose of disposing reverse osmosis (RO) brine that is generated as a result of treating ground water to drinking water standards to provide to their service area. The locations of all three wells have been provided, including an alternate location for the third well. The proposed injection zones are over 8000 feet below the Laramie/Fox Hill, the deepest aquifer presently used as a water resource and below all known USDWs, based on information from the closest wells drilled to this depth. The water quality of the formations below the Laramie/Fox Hill is expected to be greater than 10,000 mg/L TDS and will be confirmed prior to authorization to inject.

ECCV provides water and sanitation services to approximately 50,000 users in the eastern portion of Centennial and unincorporated Arapahoe County, Colorado. ECCV operates the Beebe Draw wellfield, a drinking water wellfield located approximately one mile south of Lochbuie, Colorado which consists of 12 wells ranging in depth from 72 to 89 feet.

Presently, ECCV blends the ground water from their municipal drinking water supply wells in the Beebe Draw Field with other sources because the water quality does not meet all National Primary and Secondary Drinking Water Standards. The Beebe Draw well water has elevated levels of gross alpha, TDS, fluoride, and iron. Levels of uranium and nitrates may also be elevated and may require treatment.

ECCV will continue to blend their Beebe Draw well water with other sources until about 2011 at which time adequate blending water will not be available. At that time, the withdrawal rates from the well field will triple and their RO water treatment facility will go on line. It is the RO brine from this treatment facility that will require disposal.

Initially, for about the first 5 years of operation, the well water will be a single pass through the RO membrane and the concentrate from this process will be disposed of into the injection well. In the future, to recover additional drinking water, a second,high pressure RO membrane may be installed for the concentrate to go through a second pass. The concentrations in the injectate will vary depending upon whether the RO treatment is a single or double pass. It may also be possible that only a portion of the concentrate will go through the second pass and the resulting concentration will be some average of the two. The fluctuation of the raw water concentration is nominal and will have little effect on the injectate water quality. The waste fluids from cleaning the membrane(s) will be neutralized prior to disposal into the public sewer system.

The first deep brine injection well should be completed within a year after the final permit to be able to deliver treated water in 2011.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

This Permit is issued for 10 years from the Effective Date unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1 WELL STATUS / DATE OF OPERATION		
NEW WELLS		
Well Name	**Well Status**	**Date of Operation**
ECCV DI-1	New	N/A
ECCV DI-2	New	N/A
ECCV DI-3	New	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

The Denver Basin encompasses more than 70,000 square miles and underlies the eastern portion of Colorado along the Front Range, extending into southeast Wyoming, western Nebraska, and western Kansas. The basin is bounded on the west by the Front Range of the Rocky Mountains, on the northwest by the Hartville Uplift, on the northeast by the Chadron Arch, and on the southwest and southeast by the Apishapa Uplift and Las Animas Arch, respectively. The Denver basin is an asymmetrical elongated bowl-shaped Laramide-age foreland-style structural basin with the sag deepest near Denver, where it reaches a depth of approximately 13,000 feet below the surface.

The Denver Basin contains four principal water supply aquifers that are confined systems. From deepest to shallowest, these are the Laramie-Fox Hills, Arapahoe, Denver and Dawson.

More than 1.05 billion barrels of oil and 3.67 trillion cubic feet of natural gas have been produced from wells across the Denver Basin. Currently producing sandstone reservoirs range in age from Permian through Cretaceous, with the majority producing from the latter. Minor amounts have also been produced from the Pennsylvania in the Nebraska Panhandle. Depths of production vary from less than 900 feet at the Florence field in Fremont County to about 9,000 feet at the Pierce field in Weld County.

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
ECCV DI-1

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Alluvium	0	60	< 750	Stream-deposited layers of clay, silt, sand and gravel.
Arapahoe	60	564	750	Conglomerate, sandstone, siltstone and shale.
Laramie-Fox Hills	564	1,191	550	Fine to very fine grained sandstone and siltstone interbedded with shale and coal layers.
Pierre Shale	1,191	7,200	18,700	Black to dark gray shale.
Niobrara	7,200	7,571		Chalk, shaly chalk, chalky shale, chalky limestone and bentonites.
Carlile	7,571	7,629		Siltstone, shale, sandstone, chalky limestone and marly chalk.
Greenhorn	7,629	7,819		Marine shales interbedded with limestones and chalk.
Granaros	7,819	7,965		Black marine shale with interbedded zones of thin bentonites.
Dakota Group	7,965	8,253	13,662	Gray sandstone (Lytle) brown sandstone (Plainview), gray-black shale (Skull Creek) and tan sandstone (J Sandstone).
Morrison	8,253	8,478		Claystones, siltstones, sandstones and dense limestones.
Curtis-Summerville	8,478	8,527		Red-brown mudstone and stiltsone and very fine grained sandstone and shale.
Entrada Sandstone	8,527	8,707	17,400	Red-orange to pink cross-bedded and planar-bedded sandstone.
Lykins	8,707	9,307		Red shale and siltstone with interbedded dolomte and anhydrite and red silty shale.
Lyons	9,307	9,443	19,654 - 38,610	Fine grained orange to tan or light gray sandstone (dolomitic or anhydritic) with cross bedded sandstone, siltstones and maroon shales.
Lower Satanka	9,443	9,685		Interbedded shale, siltstone, anhydrite and dolomite.
Wolfcamp	9,685	9,771		Gray to pink limestone, dolomite, anhydrite with pink, gray, or black shale and siltstone.

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Amazon	9,771	9,829	17,568	White to light gray dolomite.
Council Grove	9,829	9,981	17,568	White to light gray dolomite.
Admire	9,981	10,033		White to light gray dolomite, white limestone and chalk.
Virgil	10,033	10,283		Limestone and thin shale.
Missourian	10,283	10,381	12,394	Interbedded cherty and oolitic limestones, dark gray to black shales with light gray to buff dolomite, tan sandstone and red shales
Fountain	10,381	11,700	13,526	Gray to red siltstone and arkosic sandstone and conglomerate.
Precambrian	11,700			Gneiss, schist and granitic material.

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

The proposed injection zone is through the Permian and Pennsylvanian sandstones, limestones and dolomites at an estimated depth of 9307 to 10381 feet.

The Pennsylvanian Missouri is interbedded cream to dark brown, locally cherty and oolithic limestones and dark gray to black shales with some light gray to buff dolomite and occasional traces of tan sandstone. Increasing sandstone and red shales westward. The Virgil is composed of limestone and thin shale. The Admire is described as white to light gray dolomite on top and white limestone and chalk on bottom.

Both the Permian Council Grove and Amazon are described as white to light gray dolomite. The Wolfcamp is gray to pink limestone, dolomite, anhydrite with interbedded pink to gray or black shale and siltstone. The L Santanka is interbedded shale, siltstone, dolomite, and anhydrite. The Lyons is fine-grained orange to tan sandstone. The top of the Lyons is composed of fine grained quartz sandstones, siltstones and maroon shales which act as a major confining unit.

Based on the information from deep wells several miles away, the water quality at these depths is expected to be greater than 10,000 mg/L TDS. A water sample from each of the open formations will be isolated and sampled individually prior to authorization to inject. If the water sample indicates that any portion of the injection zone is a USDW, an application for an aquifer exemption will need to be submitted and/or the approved injection zone(s) may need to be reconsidered.

Below, the potential for induced earthquakes is discussed in response to comments received during the public comment period.

In Colorado, there have been a handful of injection activities cited to have induced earthquakes. The most well known is the Rocky Mountain Arsenal (RMA) where, in the early 60's, deep well injection occurred into the Precambrian crystalline bedrock, at a depth of 12,045 feet. The high pressure injection, 1450 psi greater than the formation pressure of 3900 psi, induced earthquakes as high as a magnitude 5. Prior to injection, faults were not known to have existed.

In the Enhanced Oil Recovery Rangely Field, there were known faults that ran through the field, in additional to two major faults running parallel to the field. An experiment was conducted to determine if earthquakes could be controlled. The findings showed that by dropping the pore pressure below a critical value of 3770 psi, the seismic activity would stop, but would start again once pressure exceeded this threshold.

The Paradox Valley Unit (PVU) is a 15,000 feet injection well injecting about 1,500 psi above formation fracture pressure. Seismic activity resulted from injection due to well documented faults in the area. To reduce the stress on the formation, biannual 20-day shut-downs were instituted to allow time for the injectate to make its way into the pores and small fractures.

In each of the events described above, the induced seismic event required a fault(s) and sufficient pore pressure to change the tectonic stress field.

Evidence of Faults

U.S. Geological Survey (USGS) tracks Quaternary faults and folds, which are sources of the magnitude 6 or greater earthquakes during the Quaternary (the past 1.6 million years), because this period of geologic time is most relevant for studies of active earthquake faults (http://earthquake.usgs.gov/hazards/qfaults). Their database shows that the closest faults/folds are located west of the area permit closer to the Foothills. The closest three are listed below and are approximately 26 miles away:

There are a series of five documented wrench faults in the vicinity of the area permit that influence present-day reservoir production in the shallower D and Muddy (J) Sandstone in the Wattenberg oil and gas field. The proposed ECCV wells lies on a block between two of these faults, the Lafayette Wrench Fault Zone (LWFZ), and the Cherry Gulch Wrench Fault Zone (CCWFZ). Based on maps in Robert Weimer's Guide to the Petroleum Geology and Laramide Orogeney, the ECCV area permit is approximately 1 to 1.5 mile away from the LWFZ and approximately 8 miles from the CCWFZ. Within the area of the 5 wrench faults, there are at least 50 oil and gas disposal and enhanced recovery wells injecting into the D and Muddy (J) sands and lower formations. Present day practices have not triggered seismic activity.

Between the major wrench faults, numerous minor faults are identified or hypothesized to exist, though their exact location is frequently difficult to define. Much of the faulting exhibited in and below the J sand is seen to terminate at the base of the Pierre Shale. Some of these lesser faults may be high angle faults, but many are listric faults, or tensional faults whose angle of dip decreases with depth and may not be tied into the basement structure. This is the nature of many of the faults in the Terry Sandstone. There are other minor synthetic and antithetic faults that have been identified in the J Sandstone which may have origins in the basement and lie within a ½ mile of the permit area boundary. Present field experience has shown that injection into these minor faults have not resulted in seismic activity.

Based on the body of literature and data available, there are no known major faults within the permit area of review, however there is the possibility of minor faults. After the well has been drilled, additional information may be gained regarding localized faults.

Stress and Pore Pressure Necessary to Induce an Earthquake

The shear stress required to trigger a fault is a function of formation pore pressure. A sufficient increase in pore pressure must exist to reduce the shear stress in the rock to cause failure. To know a priori the pressure that will cause failure, is a formidable task that involves installing a seismic network and flow modeling.

The strongest evidence to date that exists that support the statement that injection is low risk is the current UIC well injection activity in the Wattenberg and Greeley fields through which the five major wrench faults are located. There are 9 salt water disposal wells, 8 enhanced recovery wells, and one Class I injection well that are injecting into the Lyons formation and deeper. To date, there has not been any reported seismic activity as a result of these injection activities. Their distance from the ECCV injection well ranges from approximately 9 to 45 miles. Review of the maximum allowable injection pressure and injection history shows that the wells have been authorized to inject up to 3700 psi. However, except for one well, the actual maximum pressure injected has been below 2500 psi.

The closest well to ECCV is the Suckla Farm Class I Non-hazardous disposal well, permit number CO10938-02115. Since 1992, this well has been injecting into the Lyons at a depth of 9280' to 9420'. The permit maximum allowable injection pressure (MAIP) is 3700 psi, but the well has been injecting below 1000 psi.

Summary

Based on existing information, there are no known major faults within the boundary of the area of review. Additional geologic information will be obtained when the well is drilled. ECCV has a large stake in preventing and mitigating seismic activity. In addition to the proposed injection well and reverse osmosis (RO) treatment plant, their Bebe Draw drinking water supply well field is also scattered throughout their UIC permit area.

ECCV has been authorized to inject up to 3120 psi, but the final determination of the MAIP is subject to the results of the step-rate test that will be conducted once the well is constructed to determine the local formation fracture pressure. The injection pressures at other wells in the area indicate that it is probable that ECCV will be operating at a pressure lower than the MAIP. Other operators have been authorized MAIPs up to 3700 psi. With the exception of one operator, the injection pressure usually topped out at 2500 psi, and generally operating at an even lower pressure.

An additional permit requirement has been included in the permit. If there is a reported seismic event that has been verified by the USGS Earthquake Hazard Program, ECCV will cease injection. According to the USGS, the closest station is in Idaho Springs. At a magnitude ~2, seismic activity will be picked up by the USGS Advanced National Seismic System network and above a 2.5, the location can be determined. At a magnitude 2.5-3, there is low risk of structural damage.

Once ECCV has received a report of a seismic event, ECCV will report the event to EPA within 24 hours and investigate. ECCV will immediately check if the seismic event has been verified by the USGS Earthquake Hazard Program via their real time earthquake monitoring program that is readily available at http://earthquake.usgs.gov/earthquakes/ or personal communication. If a seismic activity is verified within 2 miles of the ECCV permit area, ECCV will immediately cease injection. Two miles is just beyond the distance of the closest wrench fault.

ECCV may resume injection once EPA has confirmed that continued injection into the formation(s) does not have the potential to endanger USDWs and ECCV has received verbal or written approval. Notification of all reported seismic activities will help EPA gauge if there is an increasing trend in seismic activity in the area.

A reported event is defined as either a citizen complaint or a seismic event recorded by the USGS

Earthquake Hazard Program within the 50 mile radius of the ECCV permitted area. The 50 mile extent will capture the majority of the area in the DJ basin, including the Wattenberg Oil and Gas Field that is presently used for oil and gas development. ECCV will check the USGS Earthquake Hazard Program monthly for recorded events and provide a summary in the quarterly report. Although the injection activity that ECCV has proposed is very similar, if not the same as the other disposal injection activities, ECCV has agreed to the additional requirement that has not been placed upon other operators, to alleviate the concern of the commentor and to include added vigilance in their program to protect their investments.

Although not to be implemented as a permit condition, but inherent to ECCV's operation, the injection volume is anticipated to be seasonal. The injected volume is dependent on the water usage. Based on historic water usage rates, the highest volume will occur in the summer and drop to one-third of summer usage in the winter. ECCV may even batch the RO brine and shut down injection activity for certain periods of time, rather than continuously injecting. Even if injection does not completely cease, the reduction in pressure will allow the fluids to dissipate in the pore space, alleviating the pressure built up in the formation.

TABLE 2.2
INJECTION ZONES
ECCV DI-1

Formation Name	Log	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Lyons	9150	9,307	9,443	19,654 - 38,610	0.800		N/A
Lower Satanka	9268	9,443	9,685		0.800		N/A
Wolfcamp	9525	9,685	9,771		0.780		N/A
Amazon	9663	9,771	9,829	17,568	0.780		N/A
Council Grove	9702	9,829	9,981	17,568	0.780		N/A
Admire	9802	9,981	10,033		0.750		N/A
Virgil	9934	10,033	10,283		0.750		N/A
Missourian	10002	10,283	10,381 10,220	12,394	0.750		N/A

*** P - Currently Exempted**
N/A - Not Applicable

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review. Below the potential for induced earthquakes is discussed in response to comments received during the public comment period.

The proposed injection zone is through the Permian and Pennsylvanian sandstones, limestones and dolomites at an estimated depth of 9307 to 10381 feet.

The Pennsylvanian Missouri is interbedded cream to dark brown, locally cherty and oolithic limestones and dark gray to black shales with some light gray to buff dolomite and occasional traces of tan sandstone. Increasing sandstone and red shales westward. The Virgil is composed of limestone and thin shale. The Admire is described as white to light gray dolomite on top and white limestone and chalk on bottom.

Both the Permian Council Grove and Amazon are described as white to light gray dolomite. The Wolfcamp is gray to pink limestone, dolomite, anhydrite with interbedded pink to gray or black shale and siltstone. The L Santanka is interbedded shale, siltstone, dolomite, and anhydrite. The Lyons is fine-grained orange to tan sandstone. The top of the Lyons is composed of fine grained quartz sandstones, siltstones and maroon shales which act as a major confining unit.

Based on the information from deep wells several miles away, the water quality at these depths is expected to be greater than 10,000 mg/L TDS. A water sample from each of the open formations will be isolated and sampled individually prior to authorization to inject. If the water sample indicates that any portion of the injection zone is a USDW, an application for an aquifer exemption will need to be submitted and/or the approved injection zone(s) may need to be reconsidered.

Confining Zone(s) (TABLE 2.3)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

Immediately below the Laramie-Fox Hills is the Pierre Shale that serves as a confining layer for the shallow water wells. The Pierre Shale is a black to dark gray shale estimated to be 6000 feet thick.

Directly above the top of the injection zone is the Lykins, a red shale and siltstone with interbedded persisten units of dolomite and anhydrite approximately 600 feet thick.

TABLE 2.3

CONFINING ZONES

ECCV DI-1

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Pierre Shale	Black to dark gray shale.	1,191	7,200
Niobrara	Chalk, shaly chalk, chalky shale, chalky limestone and bentonites.	7,200	7,571
Carlile	Siltstone, shale, sandstone, chalky limestone and marly chalk.	7,571	7,629
Greenhorn	Marine shales interbedded with limestones and chalk.	7,629	7,819
Granaros	Black marine shale with interbedded zones of thin bentonites.	7,819	7,965
Lykins Permian	Red shale and siltstone with interbedded dolomte and anhydrite and red silty shale.	8,707 8683	9,307 9150

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The Laramie-Fox Hills is a fine to very fine grained sandstone and siltstone interbedded with shale and occasional coal layers.

The Araphahoe consists of interbedded layers of conglomerate, sandsonte, siltstone, and shale.

The Quaternary alluvium makes up the first 60 feet of surface and consists of stream-deposited layers of clay, silt, sand and gravel.

In this part of the basin, the Denver and Dawson aquifers do not exist.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
ECCV DI-1

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Alluvium	Stream-deposited layers of clay, silt, sand and gravel.	0	60	< 750
Arapahoe	Conglomerate, sandstone, siltstone and shale.	60	564	750
Laramie-Fox Hills	Fine to very fine grained sandstone and siltstone interbedded with shale and coal layers.	564	1,191	550

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
ECCV DI-1

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12.25	9.63	0 - 1,400	0 - 1,400
Longstring	8.75	7.00	0 - 10,500	0 - 10,500

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for continuous monitoring of injection pressure, flowrate, volume, and annular pressure. In addition, it is necessary to have a mechanism to access the wellhead and injection line to obtain manual measurements of injection and annulus pressures and samples of the injection fluid. Required equipment must include: 1) continuous recording devices for injection pressure, flowrate, volume and annular pressure; 2) shut-off valves located at the wellhead on the injection tubing; 3) a flow meter that measures the cumulative volume of injected fluid; 4) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressures; and 5) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

Area Of Review

The location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, are required to be identified. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

The AOR is a quarter mile around the permit boundary. There are no AOR wells in the ¼ mile area of review that penetrate below the Lykins confining layer.

There are over two dozen water wells within the 1/4 mile area of review including the twelve wells that are part of the Bebe Draw wellfield. The majority of the wells are into the alluvium, with deepest well into the Laramie-Fox Hills at approximately 1200 feet.

There are no known or identifiable faults in the area of review.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F (if needed) and become binding on the permittee.

No corrective action is needed.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES
ECCV DI-1

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Lyons	9,307	0.800	3,375
Lower Satanka	9,443	0.800	3,420
Wolfcamp	9,685	0.780	3,315
Amazon	9,771	0.780	3,345
Council Grove	9,829	0.780	3,365
Admire	9,981	0.750	3,120
Virgil	10,033	0.750	3,135
Missourian	10,283	0.750	3,215

Approved Injection Fluid

Approved injected fluids are limited to non-hazardous waste fluid generated by the East Cherry Creek Valley Water and Sanitation District from their reverse osmosis plant and products injected during well workover and for maintenance of the well(s).

This waste stream is the concentrate or retentate from treating water from their drinking water supply wells through a reverse osmosis process to meet National Primary and Secondary Drinking Water Standards. The Beebe Draw well water has elevated levels of gross alpha, TDS, fluoride, and iron. Levels of nitrates may also be elevated. The applicant has provided an estimate of the injectate concentration with a 90 to 95 percent confidence level. Based on these estimates, a number of the analytes in the injectate will exceed National Drinking Water maximum contaminant levels where these analytes are naturally occurring in the treated water. The source water is also high in radionuclides and may be considered radioactive waste as defined by the UIC program.

In 40 CFR 144.3, the UIC definition of radioactive waste is any waste which contains radioactive material in concentrations which exceed those listed in 10 CFR part 20, appendix B, table II, column 2. The concentrations referenced are protective dose limits for individual members of the public that the Nuclear Regulatory Commission has set. These concentration limits for liquid effluents when released to the general environment is equivalent to the radionuclide concentrations which, if inhaled or ingested continuously over the course of a year, would produce a total effective dose equivalent of 50 mrem. To put this into context, according to the National Council on Radiation Protection (1987), the average radiation dose to an individual in the United States is about 360 mrem/yr. On average, 80 percent of that exposure comes from natural sources including cosmic radiation (30 mrem/yr); terrestrial radiation from natural radioactive materials in rocks, soil, and minerals (230 mrem/yr); and radiation inhaled or ingested from food and water (40 mrem/yr).

The concentrate of the injectate will vary depending upon whether it is a single or double pass through the RO plant. In a single pass through the RO membrane, the injectate concentration will unlikely exceed the radioactive waste threshold limits as defined in 40 CFR 144.3. However, if there is a double pass, it is highly probable that it is a radioactive waste as defined by UIC regulation 40 CFR 144.3. This injectate will be injected into a deep Class I disposal well, below all underground sources of drinking water, with construction and monitoring requirements that will prevent the injected fluids to endanger USDWs.

Since the reverse osmosis treatment plant has not been installed yet, the injectate concentration is estimated with a 90 to 95 percent confidence level. The waste fluid will be sampled and characterized prior to authorization to inject.

Injection Pressure Limitation

Except during stimulation and performing required formation test(s), injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in injection zone(s).

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit,

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

The MAIP is initially set at 3120 psi, the limiting pressure when each formation is individually calculated across the entire injection zone.

The applicant does not have site specific information on the fracture gradients for the proposed injection zones. Estimated fracture gradients were used to determine the permit MAIP. Prior to authorization to inject, 4 zones will be isolated and step rate tests will be conducted on each individual zone. These four zones are: 1) Missouri, 2) Virgil and Admire, 3) Council Grove, Amazon and Wolf Camp, and 4) Lyons. The L Satanka formation will not initially be used as an injection zone. In the zones where more than one formation is open to receive fluids, during the step rate test, a spinner will be placed within 25 feet of the base of the uppermost formation.

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Presently, there are no aquifer exemptions associated with this permit and there are no fluid volume limits. However, if an aquifer exemption is requested based on TDS data from the injection formations, and if granted, then a fluid volume limit will be determined at that time.

Mechanical Integrity (40 CFR 146.8)
An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Part I (Internal) MI will be demonstrated prior to beginning injection and at least once every five (5) years after the last successful demonstration of Part I MI. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing, or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, whichever is less, with ten (10) percent or less pressure change over thirty (30) minutes.

Part II (External) MI will be demonstrated using a temperature log. A baseline temperature log will be required prior to authorization to inject, a temperature log will be run within six to twelve months after injection has commenced, and subsequent temperature logs will be run at least once every five (5) years after the last successful demonstration of Part II MI.

In addition to the required temperature log discussed above, should the analysis of the cement bond log show inadequate cement behind pipe to prevent significant movement of fluid out of the approved injection zone of the annulus cement, i.e. less than 80% bond index cement bond across the confining zone, a Radioactive Tracer Survey will be required prior to authorization to inject.

Annual Falloff Tests (40 CFR 146.13 (d)(1))
The pressure falloff test is required for Class I operations and must be performed at least once every twelve months for the purposes of monitoring pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone and to aid in determining the lateral extent of the injection plume.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
Quarterly, the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, specific gravity, and any additional constituents specified in APPENDIX D of the Permit. This analysis shall be reported to EPA as part of the Quarterly Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Continuous monitoring of the injection pressure, annulus pressure, injection rate, and injected volumes shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection and annulus pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure is required to be reported as part of the Quarterly Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Financial Statement, received November 9, 2009

Evidence of continuing financial responsibility is required to be submitted to the Director annually.